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Distributed Interruptible Load Shedding and micro-generator dispatching for smart grid contingencies

R. Argiento, R. Faranda, A. Pievatolo and E. Tironi

Abstract – Black-outs are the worst end results of significant differences in power between generations and absorptions. Therefore, the capability of distribution network operators (DNO) of knowing in advance and controlling the load profile is surely more and more an important means to run in an acceptable way an electric power network, as a smart-grid, especially in presence of distributed generation. The combination of Distributed Interruptible Load Shedding and micro-generators dispatching is an interesting opportunity for the DNO in case of power network emergency management. In this paper, a proposal to approach this problem and some test results are presented, using probabilistic methods, in the case of a small low-voltage network with interruptible loads and micro-CHP (Combined Heat and Power) generators.

Index Terms – Black out, Demand Side Management, Distributed Interruptible Load Shedding, μ CHP, CHP, Uncertain System.

I. INTRODUCTION

Smart grids are opening new scenarios for electrical networks. The capability of controlling the load is surely an important means to run an electrical power network. This is why load shedding (LS) and demand side management (DSM) programs are becoming more and more widespread among electricity users.

The diffusion of distributed generation (DG) can be a further opportunity for improving the management of the electric system. DG is gaining interest worldwide in governments and industry. The reasons for this were initially determined by environmental and market considerations. In fact DG can exploit clean and renewable energy sources and favours energy savings through the combined production of thermal and electric energy; furthermore, the opening of markets in the energy sector, above all of electricity and gas, has allowed the entrance of a greater number of small producers. Recently, following the technological developments in the field of small generation systems (particularly micro turbines and fuel cells), other aspects of DG are being investigated, such as those related to the improvement of the quality and reliability of the energy supply obtained from auto-production.

For the purpose of this article, it is also important to underline that in most applications energy is needed in different forms, such as for end-users [1].

The diffusion of DG in electric power networks will also facilitate the installation of μ CHP systems, which have a mainly disperse nature and which will probably replace traditional heating systems provided incentive schemes are implemented by regulatory authorities [2].

The presence of numerous distributed energy sources, including the μ CHP, will offer the opportunity of improving the operation of the distribution system, provided that the distribution utility can integrate these additional resources in the network operation system. In particular, to go beyond the DG as an aid to the relief of transportation lines and include emergency operations, it is necessary that the distribution network operator (DNO) be allowed to condition the electricity production of the distributed sources, so as to integrate dispatchable DG within its LS and DSM programmes, using suitable tariff incentives for the service offered to the final users [3, 4].

In this article we investigate this point as a follow-up to a previous study on Distributed Interruptible Load Shedding (DILS) [5] (where load relief is obtained by curtailing diffuse interruptible loads in a decision-under-uncertainty framework), now the load variation can be achieved also through the dispatchment of power from distributed micro-generators. In particular, we examine the convenience of CHP and μ CHP systems in Section II and we assess the influence of the power they generate on load profile in Section III. Then, in Section IV we present the probabilistic decision methodology by which the DNO can obtain the desired load variation from a large enough group of residential customers; in Section V we explain how some relevant parameters summarizing the features of residential load can be obtained, along the same lines of the bottom-up approach introduced by [6]; Section VI contains numerical examples, followed by conclusions in Section VII.

Some information reported in the paper was obtained from a RSE (Ricerca sul Sistema Energetico) report (a part of the milestone CAREL of the ECORET project), which was developed within the research activity “*Ricerca di Sistema*”, Italian Ministry D.M. 26.01.2000.

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II. CHP VS μ CHP SYSTEM

With the aim of improving the use of primary sources of energy, it can be convenient to combine the heating consumption with a system for the generation of secondary energy having a high economic value and easily transportable, such as electricity or fuel (hydrogen, for example). A method for achieving this is known as cogeneration system (Combined Heat and Power: CHP).

High-power CHP systems have been and are still very useful, especially in industry. Nowadays CHP systems can be advantageous also for final end-users, since their cost has reduced relatively to the cost of energy and because of technical advances in smaller thermal machines. Finally, an increased sensitivity of final users towards systems with high energetic efficiency has stimulated research to study numerous solutions for the optimization of these applications.

As example Fig. 1 illustrates schematically the gain in efficiency obtainable through μ CHP (the numbers reproduced in the diagram are from a report of the Directorate General for Energy of the European Union, cited by [7]). We can see that the same quantities of electric and thermal energy are obtained from 148 units with the separated production (a)+(b), against 100 unit with the combined production (c)¹. Comparing the input and the output of (a)+(b) versus (c), we find that the former has an efficiency of 57%, whereas the latter reaches an 85% efficiency, by using thermal energy from power generation equipment for cooling, heating and humidity control systems. These systems have to be located at or near the facility using power and space conditioning, and can save, according to Fig. 1, about 32% of the input energy required by conventional systems.

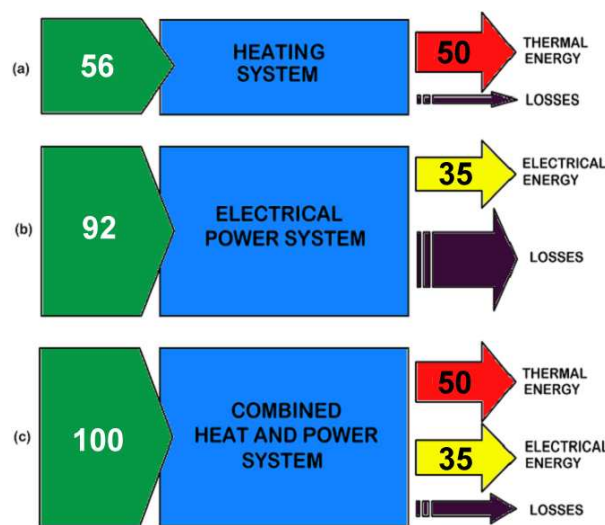


Fig. 1 – Example of subdivision among electric energy, thermal energy and losses with two distinct production systems, (a) and (b), and with a cogeneration CHP system (c), with the same output of electric and thermal energy.

As another example, the energy consumption of a country like Italy is divided into three almost equal parts. The 2007 “Relazione Generale sulla Situazione Economica del Paese” (General Report on the Economic Situation of the Country) [8] shows that industry, transport and civil uses equally share a consumption slightly greater than 140 Mtoe (Million of tons of oil equivalent). Heating for civil uses (residential, commerce, services and public administration) has a significant role: in 2007 Italy consumed 23.77 Mtoe of gas and 4.83 Mtoe of oil derivatives for it and, based on data of previous years, one observes that such consumption has been steady for several years. Considering these figures, it is easy to see how the 30 Mtoe of heat dispersed every year through the wastewaters of its power stations, could cover the country needs (but only about 5 Mtoe are currently re-used).

Clearly it is not possible to transfer these 30 Mtoe of wastewater heat in millions of homes on a very diverse terrain, whereas co-generative electric power systems have a mainly distributed nature. Nowadays they can be implemented fruitfully by small μ CHP plants, which can generate heat and electricity for large structures (such as hospitals or hotels), small urban centres and are also available for households. In this latter case, combustion in small cogeneration stations can reach savings from 20% to 40% of primary energy sources [9].

This technological solution is possible thanks to μ CHP systems which operate as a function of a user's thermal needs, generating also electricity for the same user or his neighbours.

Nowadays there exist μ CHP systems for residential use that are silent and are supplied with gas or diesel. The most advanced is probably the system which uses an internal combustion engine of Stirling type, but also technologies based on μ turbines, steam or organic oil seem to be attractive alternatives for this type of application [10].

The advantages associated with this technology can be better appreciated by looking the example reported in Fig. 2.

¹ In this example we have neglected transmission losses, investment and plants costs for the transportation of electricity to consumption points.

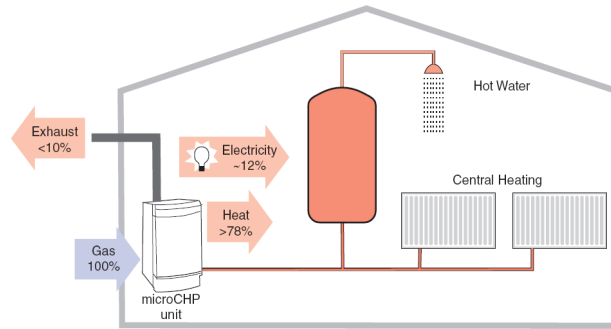


Fig. 2 – Diagram of operation of a μ CHP cogeneration system

A normal thermal energy requirement for residential heating should have a production varying between 6 thermal kW (kWt) for a small flat and 12 kWt for a detached or semidetached house. As an example, among the available commercial machines, the Whispergen PPS24-ACLG-5 model provides the following power range: 5.5 kWt minimal, 7.0 kWt nominal, 12.0 kWt maximal, with a maximal gas consumption of 1.55 m³ per hour. In particular, this machine can produce 78% of heat (with 1.209 m³ per hour of gas) and 12% of electricity (with 0.186 m³ per hour of gas), whereas the remaining 10% are flue losses (0.155 m³ per hour of gas).

From the point of view of the heating, this 12% electricity could be viewed as a loss, because the same quantity of heat can be obtained from a traditional heating system (with an efficiency of 89%) using only 1.358 m³ of gas per hour. But this electricity is easily transportable and in this case it is produced near the utilization point, giving a further efficiency advantage; furthermore it would not be generated by power stations, which have a 44% average efficiency (55% for newly built power stations [11]), after which the transmission and distribution efficiency (being slightly greater than 90%) must also be taken into account.

In summary, to produce this 12% electricity, about 0.423 m³ of gas per hour would be needed in a traditional power station (considering an efficiency of 44%), against, as shown, the 0.186 m³ of gas per hour with the μ CHP system, thus saving 0.237 m³ of gas per hour.

Hence with a small increment of the direct gas consumption by the final users of about 15% (1.55 m³ instead of 1.358 m³), if all the heating for civil use was of the μ CHP type, it would be possible, in Italy, to switch off five power stations (or to avoid building them to meet an equivalent increase in the demand of electricity).

III. LOAD PROFILES AND COGENERATION

The paper [5] analyzes the hourly load profile of a group of residential users and break it up to separate the power absorbed by the different appliances. This information is used by the DNO to send appropriate power reduction signals to end-users to achieve a desired load shedding (this procedure is called Distributed Interruptible Load Shedding – DILS). Here we must also include the information on the additional power associated with the thermal load of users of μ CHP, contributing to the actual load profile. This determines in fact the power that could be dispatched to the network by the DNO in case of emergency.

We start by reporting in Fig. 3 the electric load of 1000 families in a typical working day in winter and in summer, subdivided by appliance. Then, in Fig. 4, we show the thermal load (central heating and hot water), again both in winter and in summer, for the same 1000 families. In particular in Fig. 4, the hypothetic electric generation reported is derived assuming that 25% families have a μ CHP system installed (the same described in the previous paragraph) multiplying the thermal load by (0.12/0.78).

Because of the families' auto-generation of part of the needed electricity, the winter load profile, of Fig. 3(a), is modified significantly, with less pronounced peaks and an overall reduction on average, whereas the summer load profile, of Fig. 3(b), is essentially unmodified, except for a small reduction of the highest peaks. Then in such a condition the DNO must supply a generally smaller load, as seen in Fig. 5 (a specific analysis on the effect of μ CHP systems on the aggregated load profile can be found in [12]).

Now we should evaluate the power available to the DNO for dispatching, in addition to the power taken by the interruptible loads (which in the following will be the air conditioner, the water boiler, the dishwasher and the washing machine). To do this we must identify how many μ CHP system can actually produce additional power on request (dissipating the excess heat through the flue).

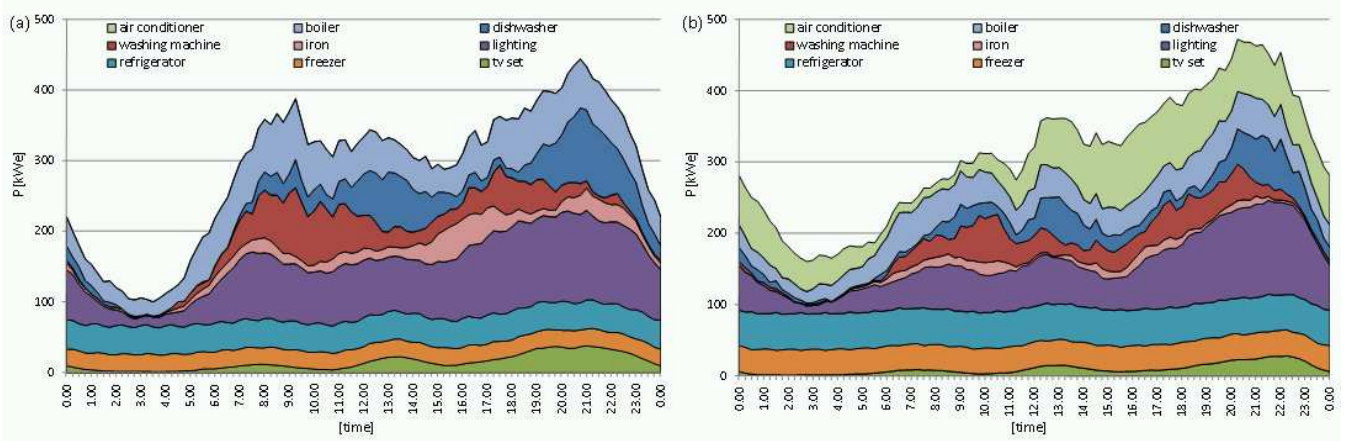


Fig. 3: Electric energy consumption of a group of 1000 families subdivided by appliance: (a) winter, (b) summer.

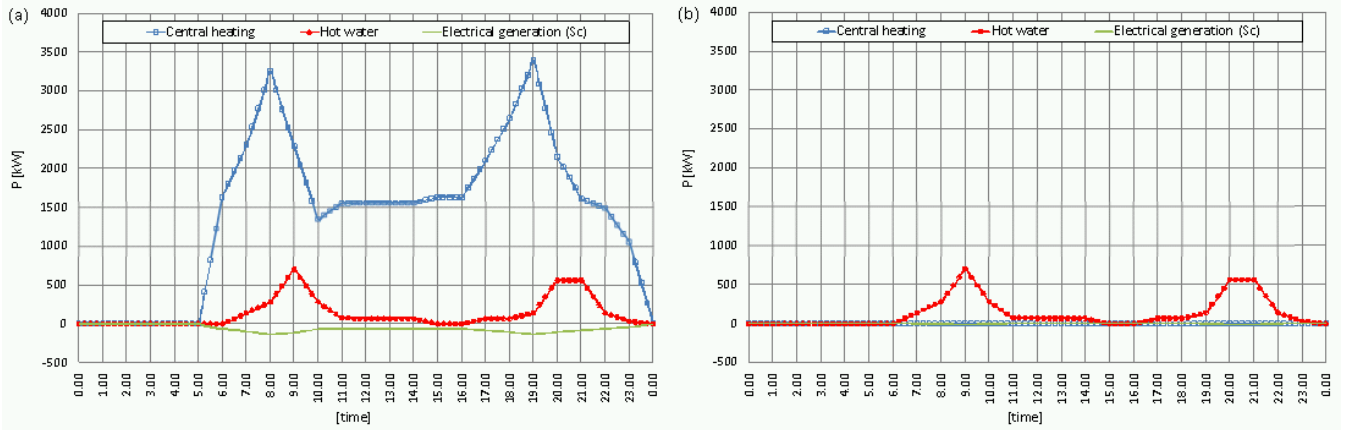


Fig. 4: Thermal energy consumption of a group of 1000 families and electric energy produced by 25% families having a μ CHP: (a) winter, (b) summer.

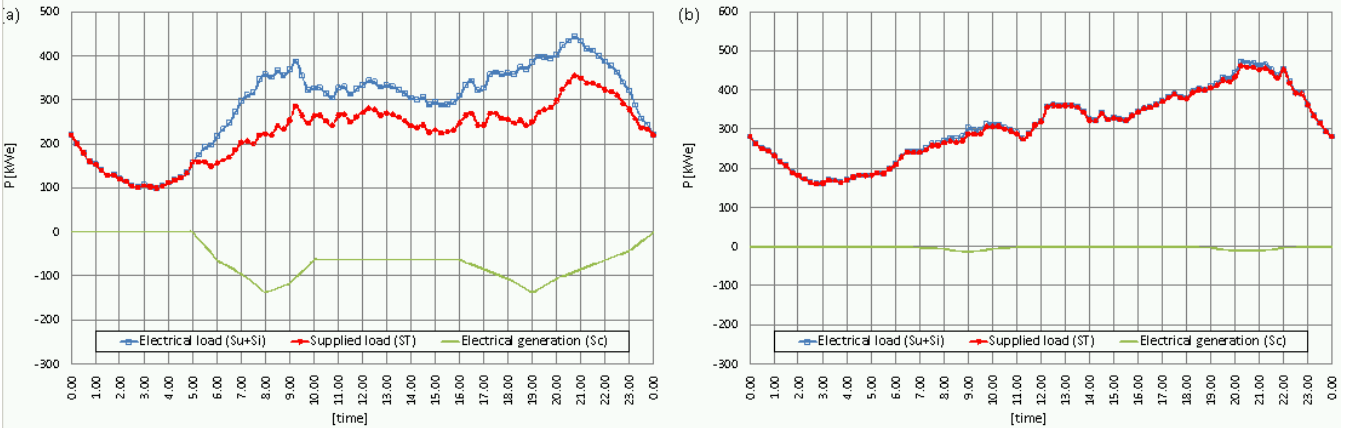


Fig. 5: Electric load supplied to 1000 families by the public network with μ CHP systems: (a) winter, (b) summer.

In Fig. 6 we have plotted the overall power available to the DNO for operating the DILS, the graphics is obtained summing the interruptible loads of Fig. 3 and the additional dispatchable power². The maximal average power obtainable by a μ CHP unit, assuming the homes where it is installed as subdivided into 80% flats and 20% detached or semidetached houses, was calculated as follows:

- in winter, we assumed that 100% of μ CHPs are on, so that any μ CHP system can generate up to $(12 \cdot 0.2 + 6 \cdot 0.8) \cdot (0.12 / 0.78) = 1108 \text{ We}$;
- in summer, we assumed that only 50% of μ CHPs are on.

Of course, these figures should be adapted for every concrete case, and they are used here only as an example to appreciate the available power and what the shape of its profile could look like. What one sees is that now the total available power is

² This value is obtained by the electrical generation and considering that the μ CHP are always ignited in stand-by. The excess of produced heating required only in case of emergency is dispersed in fireplace.

greater than just the interruptible power, so that it will be easier to operate the network in case of excess load requirements or of malfunctioning. However, one should also bear in mind that the cost to the DNO of this available energy coming from the μ CHP units is larger than that provided by the interruptible load.

We can also notice from Fig. 6 that the interruptible power in winter, excluding the peaks, tends to be smaller than in summer, because there are no air conditioners on. The inclusion of the dispatchable power from μ CHP units increases the available power in winter sensibly. In this way we can overcome a limitation of the DILS, which could be less effective in winter due to the little interruptible power available at certain hours.

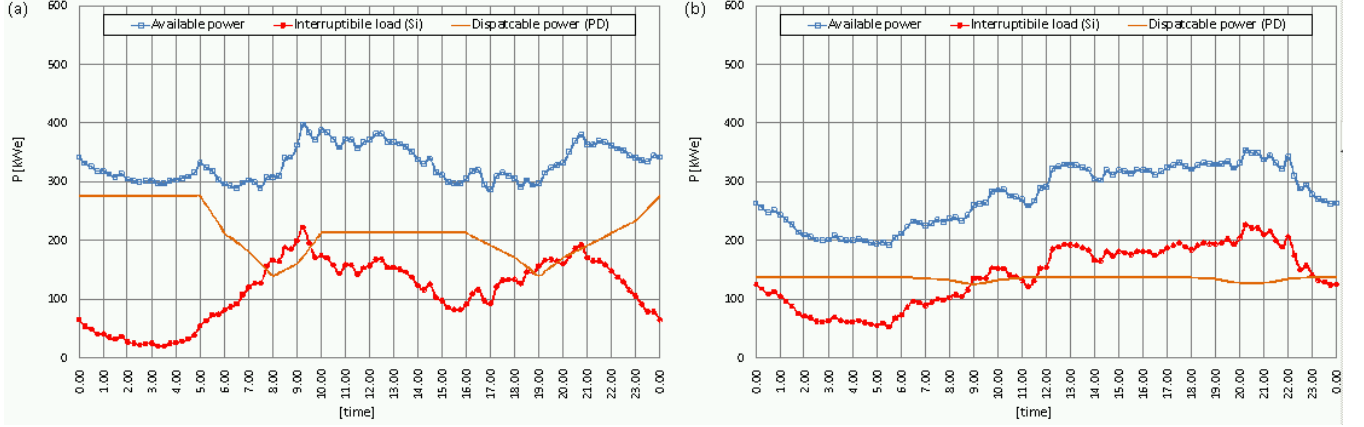


Fig. 6: Available power of a group of 1000 families with 25% possessing a μ CHP system: (a) winter, (b) summer.

IV. LOAD RELIEF ACTIONS BASED ON EXPECTED COST MINIMIZATION

In this section we first build a stochastic model describing the overall load of a network where the load of each user can be subdivided into three parts: the interruptible part, the uninterruptible part and the power provided by the user (negative load). With the help of the model we will be able to calculate the expected cost that the DNO must incur after an emergency load relief action. Such cost is defined as a function of the percentage p of load reduction and of the percentage q of available dispatchable power requested to each participant user. The cost function will be minimized with respect to p and q . This construction follows closely the procedure illustrated in [5], with the addition of the dispatchable power.

The average load of user i at time t (measured in hours) can be written as:

$$Y_{T,i}(t) = Y_{U,i}(t) + Y_{I,i}(t) - Y_{C,i}(t), \quad i \in 1, \dots, N \quad (1)$$

where $Y_{U,i}(t)$, $Y_{I,i}(t)$ and $Y_{C,i}(t)$ denote the uninterruptible power, the interruptible power and the power produced by the cogenerator, respectively. Since not all the users are interruptible and not all of them own a μ CHP system, $Y_{I,i}(t)$ is zero for a known set of i indexes and $Y_{C,i}(t)$ is zero for another known set of indexes, the latter being not necessarily equal to the former. The power produced by each user has a maximal value indicated by $y_{\max,i}$. The overall network load at time t is obtained by summing the load of all users:

$$\begin{aligned} S_T(t) &= \sum_{i=1}^N Y_{U,i}(t) + \sum_{i=1}^N Y_{I,i}(t) + \sum_{i=1}^N Y_{C,i}(t) = \\ &= S_U(t) + S_I(t) - S_C(t) \end{aligned} \quad (2)$$

where new symbols have an obvious meaning, $S_C(t)$ belongs to $[0, S_{C,\max}]$ and $S_{C,\max} = \sum y_{\max,i}$.

As assumed by [5], the DNO, using historical data, can forecast the load that will be requested at time $t+u$, $S_T(t+u)$, with a negligible error. To obtain a load relief, it must operate on the interruptible load, $S_I(t+u)$, by requesting a fraction p , and on the dispatchable generation, $P_D(t+u) = S_{C,\max} - S_C(t+u)$, by requesting a fraction q . Let us assume that the intervention lasts one hour and that the needed relief is r kW. To carry out this operation, the DNO must incur a cost that changes as a function of the outcome of the relief action: if it succeeds then one has a cost c_1 for every kWh of interruptible energy unsold in that hour and a cost c_2 for every kWh of dispatched energy; if it fails, one has the separation of the network, assumed to last 4 hours, costing c_3 for every kWh of unsold energy in this time interval. Cost coefficient c_2 includes the remuneration of both the dispatched energy and the unused heat produced in excess. All this is summarized by the following expression of the cost function:

$$\begin{aligned} c(p, q, S_I, S_C) &= (c_1 \cdot p \cdot S_I + c_2 \cdot q \cdot P) \mathbf{I}(p \cdot S_I + q \cdot P_D \geq r) + \\ &+ c_3 \cdot \int_{t+u}^{t+u+4} S_T(v) dv \mathbf{I}(p \cdot S_I + q \cdot P_D < r) \end{aligned} \quad (3)$$

where $\mathbf{I}(\cdot)$ is the indicator function and where the load components are evaluated at time $t+u$.

The cost function (3) depends on the random and unobservable quantities S_I and P_D , however, denoting by s the forecasted value of $S_T(t+u)$, and postulating a joint probability distribution for (S_U, S_I, S_C) , an optimal value of (p, q) is obtained minimizing the conditional expected value of the cost:

$$c(p, q) = E\{c(p, q, S_I, S_C) | S_T(t+u) = s\}. \quad (4)$$

Assuming that the users act independently and invoking the Central Limit Theorem, we can regard S_U , S_I and S_C as Gaussian random variables. Assuming also they are stochastically independent, the calculation of (4) becomes easy thanks to the properties of the multivariate Gaussian distribution [13], provided that the necessary means and variances are assigned. In fact, let us denote by n_I the number of interruptible users and by n_C the number of users who own a μ CHP; then let μ_T , μ_I , μ_C and σ_T , σ_I , σ_C be the means and the standard deviations of $Y_{T,i}(t)$, $Y_{I,i}(t)$ and $Y_{C,i}(t)$ (where the last two variables are nonzero when appropriate). Then the joint distribution of (S_I, S_C) , given $S_T=s$ is bivariate Gaussian with mean vector

$$\mu_{S_I, S_C|s} = \begin{pmatrix} n_I \cdot \mu_I \\ n_C \cdot \mu_C \end{pmatrix} + \begin{pmatrix} n_I \cdot \sigma_I^2 \\ -n_C \cdot \sigma_C^2 \end{pmatrix} \cdot \frac{s - N \cdot \mu_T}{N \cdot \sigma_T^2} \quad (5)$$

and covariance matrix

$$\Sigma_{S_I, S_C|s} = \begin{pmatrix} n_I \cdot \sigma_I^2 & 0 \\ 0 & n_C \cdot \sigma_C^2 \end{pmatrix} - \begin{pmatrix} n_I \cdot \sigma_I^2 \\ -n_C \cdot \sigma_C^2 \end{pmatrix} \cdot \frac{n_I \cdot \sigma_I^2 - n_C \cdot \sigma_C^2}{N \cdot \sigma_T^2} \quad (6)$$

(the t argument to means and variances was removed for notational simplicity).

V. MEAN AND VARIANCES OF THE LOAD COMPONENTS

The parameters appearing in (5) and (6) were determined directly, as far as μ_U , μ_I , μ_C , σ_U , σ_I and σ_C are concerned, whereas, μ_T and σ_T are derived through the following expressions

$$\begin{aligned} \mu_T &= \mu_U + \mu_I - \mu_C \\ \sigma_T^2 &= \sigma_U^2 + \sigma_I^2 + \sigma_C^2 \end{aligned} \quad (7)$$

(see eq. (1)), with obvious meaning of the new notation. As for μ_U , μ_I , σ_U and σ_I , they were derived based on a study on residential uses of appliances by CESI³, as explained in detail in the Appendix. As for μ_C and σ_C , we only have the data plotted in Fig. 4, so we proceed heuristically, with no prejudice for the substance of the load relief method proposed. The only available estimate of μ_C at each hour is the ordinate of the curve of electric generation in Fig. 4 (after dividing it by the number of users). To derive the hourly σ_C , let p_C be the probability that a user (who owns a μ CHP) is using it at in a given hour and let $P_{\text{nom},e}$ be its nominal power. Then

$$\begin{aligned} \mu_C &= p_C \cdot P_{\text{nom},e} \\ \sigma_C^2 &= p_C \cdot (1 - p_C) \cdot P_{\text{nom},e}^2 \end{aligned} \quad (8)$$

and, deriving p_C from the equation of the mean, we can insert its value in the equation of the variance. The nominal power $P_{\text{nom},e}$ is set equal to 0.646 kW, based on the nominal thermal power of a house (7 kWt) and of a flat (3.5 kWt), see Section II around Fig. 2, using the subdivision of homes into houses and flats of Section III:

$$P_{\text{nom},e} = (7 \cdot 0.2 + 3.5 \cdot 0.8) \cdot \frac{0.12}{0.78} = 0.646.$$

VI. NUMERICAL EXAMPLES

In this section we illustrate the results of the minimization of the expected cost function (4) with respect to p and q in different settings. The example we considered concerns a network with N users, of whom n_I participate in the DILS programme and n_C own a μ CHP system qualified for the supply of power to the network. The two groups of users can coincide partially. For simplicity we suppose that all the μ CHP owners accept that their cogenerator is used by the DNO for dispatching; if not, the $Y_{C,i}$ component in eq. (1) could be subdivided into dispatchable and non-dispatchable part without difficulty.

The examples we examine concern two types of emergencies:

1. the first one, at 3am, is a situation of reduced load. In this case, a load variation action could be necessary if a failure occurs in the power generation (a transformer or a transmission line, for example). We have supposed that the power generation deficit is equal to 10% of s , while s is equal to the mean load at 3am, that is:
 $s = N \cdot [\mu_T(3) + \mu_C(3)] - n_C \cdot \mu_C(3);$
2. the second one, at 9pm, is a situation of inspected high load. In this case the DNO must remedy an excess of demand with respect to the load capacity of the network. We have supposed that the inspected high load is 10% higher than the mean load at 9pm, therefore:
 $s = 1.1 \cdot \{N \cdot [\mu_T(21) + \mu_C(21)] - n_C \cdot \mu_C(21)\}.$

To take seasonal variations into account, we have done the analyses in a typical working day both in winter and in summer. These four combinations hour/season have been tested in two different experimental conditions:

- a) a required load variation of 10% of the forecasted load at time $t+u$ (that is, $r=1.1 \cdot s$ kW), $N=1000$, $n_I=500$, $n_C=250$ in winter

³“Contributo delle elettrotecnologie per usi finali al carico di punta” (Contribution of electro-technologies for final uses to the peak load), ECORET/workpackage 1 (PRECA)/milestone 1.2 (CAREL) /report 1/1 of the milestone. Developed within the “Ricerca di Sistema” framework.

and $n_C=125$ in summer;

b) a required load variation of 10% in the same conditions, but with $n_I=250$.

The first conditions refer to a moderate required load relief with a relatively high number of interruptible customers, then we examine a more severe situation where the interruptible power is halved.

The cost parameters used in (3) are $c_1=c_3=1$ and $c_2=5$. The quotient c_2/c_1 is the ratio between how much the network operator presently pays in Italy for a kWh of photovoltaic energy supplied by a residential user (0.42€) and how much a user pays for a kWh of electricity supplied by the network (0.09€); it gives a tentative measure of the remuneration of dispatchable energy.

The means and variances to be inserted into (5) and (6) are displayed in Table 1, from which the values of s in Tables 2 and 3 can be obtained as described above (up to rounding errors).

Table 1: Means (kW) and variances (kW²) of the components of individual load at 3am and at 9pm, in winter and in summer

	μ_T	σ_T^2	μ_I	σ_I^2	μ_C	σ_C^2
Winter 3am	0.095	0.040	0.020	0.026	0.001	0.001
Winter 9pm	0.238	0.545	0.240	0.369	0.335	0.104
Summer 3am	0.115	0.042	0.024	0.030	0.000	0.000
Summer 9pm	0.413	0.359	0.214	0.318	0.087	0.041

The results of the two experiments are reported in the following Tables 2 and 3, where by $\mu_{S_I|s}$ and $\mu_{P_D|s}$ we have denoted the conditional mean of the interruptible load and of the available dispatchable power, respectively, as derived from (5). Multiplying these values by p and q , respectively, one gets the expected power obtained from the DILS action and the μ CHP dispatchment.

In Table 2, we notice that the load relief need is met by the interruptible load alone, except for 3am in winter, when it is necessary to use 1% of the dispatchable energy available, because the interruptible load is insufficient. Then, the number of interruptible customers have been halved in the second experiment, so as to check whether, with the present cost structure, it could be convenient to request more dispatchable energy to avoid the network separation, which is what actually happens, as shown in Table 3. Even though at 9pm, both in winter and in summer, the interruptible load would be barely sufficient to achieve the desired load variation, still a fraction of dispatchable power is requested because of the uncertainty associated with the interruptible load. The result at 3am in winter is due to the essentially constant value of $c(p,q)$ in the direction of p : this is so because the very small value of interruptible power would modify the probability of a black out negligibly, even though it was used entirely.

In order to appreciate the type of shape taken by the cost function, we have plotted three typical cases that occur in both experiments: the one where a fraction of the interruptible load alone meets the load relief need (Fig. 7); the one where 100% of interruptible load is needed, plus a fraction of dispatchable power (Fig. 8); the one where the recourse to the interruptible load does not modify the probability of a black-out and the load relief is got from the dispatchable energy alone (Fig. 9).

Table 2: Experiment 1, with 10% expected-load relief request with a network of 1000 residential users.

	Winter 3am	Winter 9pm	Summer 3am	Summer 9pm
s [kW]	95.768	537.634	114.985	537.703
r [kW]	9.577	53.763	11.499	53.770
$\mu_{S_I s}$ [kW]	10.091	139.364	10.091	128.190
p	100%	50%	100%	54%
$p \cdot \mu_{S_I s}$ [kW]	10.091	69.682	10.091	69.223
$\mu_{P_D s}$ [kW]	276.641	195.872	138.425	128.400
q	2.24%	0.00%	5.76%	0.00%
$q \cdot \mu_{P_D s}$ [kW]	6.196	0.000	7.973	0.000

Table 3: Experiment 2, 10% expected-load relief request with a network of 1000 residential users and 250 interruptible users (halved with respect to experiment 1).

	Winter 3am	Winter 9pm	Summer 3am	Summer 9pm
s [kW]	95.768	537.634	114.985	537.703
r [kW]	9.577	53.763	11.499	53.770
$\mu_{S_I s}$ [kW]	5.046	69.682	5.046	64.095

p	0.28%	100%	0.00%	100%
$p \cdot \mu_{S_I S}$ [kW]	0.014	69.682	0.000	64.095
$\mu_{P_D S}$ [kW]	276.641	195.872	138.425	128.400
q	3.48%	1.89%	8.31%	6.26%
$q \cdot \mu_{P_D S}$ [kW]	9.627	3.702	11.503	8.038

The expected cost function was minimized with the simplex method by Nelder and Mead [14], as implemented in the GNU Scientific Library. The method can converge to non stationary points, but it is convenient because it does not require the calculation of derivatives. This feature is handy in our case because even the expected cost function itself does not have a closed analytic form. To avoid false convergence, the solution found has been validated by calculating the function on a fine grid in different neighbourhoods of the solution itself.

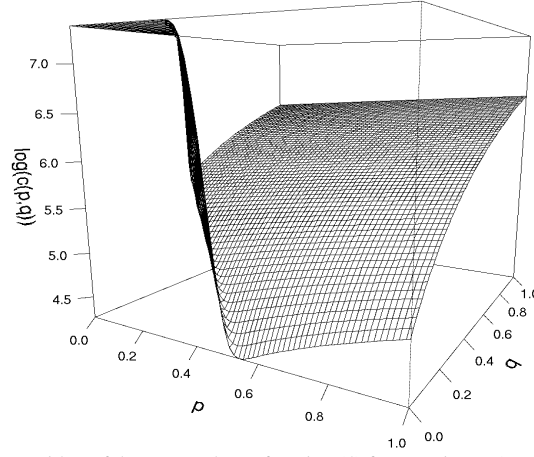


Fig. 7: Logarithm of the expected cost function (4) for experiment 1, summer 9pm.

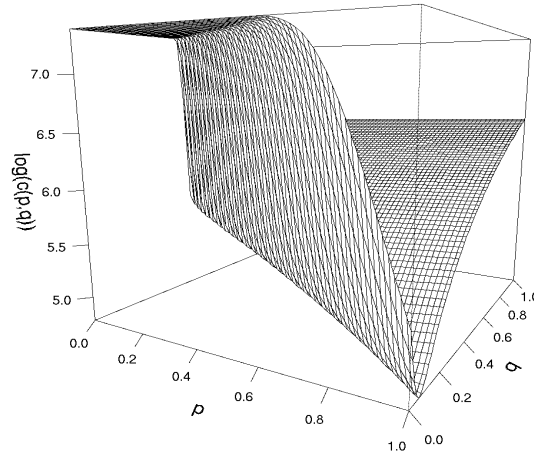


Fig. 8: Logarithm of the expected cost function (4) for experiment 2, summer 9pm.

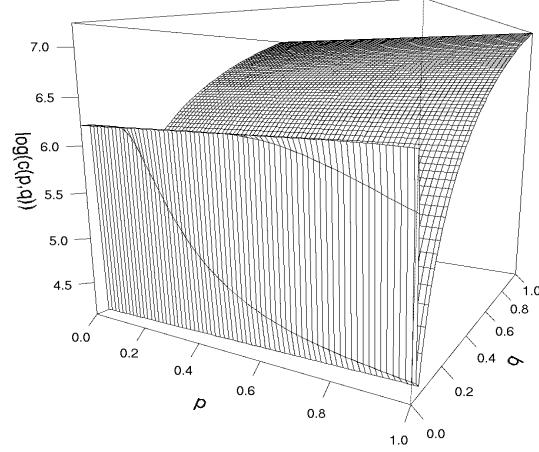


Fig. 9: Logarithm of the expected cost function (4) for experiment 2, winter 3pm

VII. CONCLUSIONS

Electricity distribution networks are about to undergo profound changes. In fact, small-sized distributed generation systems are becoming widespread: the expression “smart grid” is used very frequently to describe the new low-voltage distribution network. In the future the traditional distribution grids will be equipped with computer networks to allow for real time information exchange among the different components of the electric system, the distributed generators and the final users. Among the expected results, there is a better management of the entire system, from the point of view of both service quality and energetic efficiency.

In particular, future sceneries include the possibility of operate the network when differences between the requested and the available power occur, not only by means of distributed load reliefs, but also possibly resorting to power injection by dispatchable distributed generators owned by the final users.

In this work, we have assessed the possibility of sending two different signals to end-users with the aim of reaching a desired overall load variation (one to loads and the other to micro-generators). These two signals (p and q) are common for all the end users and they are respectively applied to the interruptible load and to the dispatchable generation. The best values of the two signals are obtained by minimizing a predefined cost function, which depends on the target load relief and of the costs of interruptible energy, of dispatchable energy and of a black-out. The minimization of the cost function is done in a probabilistic decision framework, showing how the possibility of interacting with uncertain loads and micro-generators could give the DNO an effective means of making the event of a black out much less likely.

Our experiments, although made in specific cases, have highlighted the role played by the number of users who accept to participate in programmes of load relief and power production in case of contingency. In particular, still as an example, we have indicated the variety of actions to be performed in the network in different periods of the year and times of the day. With the assumed cost structure, we obtain that, where the interruptible power alone is not sufficient to carry out the load relief, then it is convenient to resort to a small portion of dispatchable power.

VIII. APPENDIX

We show here how to derive μ_U , μ_I , σ_U and σ_I used in eq. (7), which are to be interpreted as means and standard deviations at the start of a specified hour. The derivation is independent of the subscript, so we use μ and σ without subscript in this section. The report of CESI finds these parameters by averaging the results of a computer simulation of a high number of users in a typical working day, by means of a software called SCUDO. To speed up the process, we found approximate explicit formulae using the same input values, keeping in mind that a very accurate characterization of residential users behaviour is not the main focus of our paper.

Let us denote by $W = \sum_{a=1}^A W_a$ the power taken by A appliances, with W_a being the power taken by appliance a , with mean and standard deviation μ_a and σ_a . If appliances are independent, $\mu = \sum \mu_a$ and $\sigma^2 = \sum \sigma_a^2$, then we are left with the task of finding μ_a and σ_a at a given time t .

For appliances that repeatedly change their state from on to off (such as the refrigerator or the freezer), we used the following formula:

$$\mu_a = p_a \cdot p_d \cdot p_t \cdot \frac{l_{\text{on}}}{l_{\text{on}} + l_{\text{off}}} \cdot P_{\text{nom}}$$

$$\sigma_a^2 = p_a \cdot p_d \cdot p_t \cdot \frac{l_{\text{on}}}{l_{\text{on}} + l_{\text{off}}} \cdot P_{\text{nom}}^2 - \mu_a^2$$

where p_a is the probability that the user owns the appliance, p_d is the probability that it is ever used on any given day, p_t is the

probability that it is used at time t , given that it is used in the day. l_{on} and l_{off} are the average durations of the on and off states and P_{nom} is the nominal working power of the appliance. All these parameters are appliance-specific and are given as inputs to SCUDO in the CESI report. The formula was obtained from the chain rule for the factorization of the joint probability.

In a slightly more complicated way, but with a similar procedure, we can obtain the moments of cycle appliances (such as the dishwasher, the washing machine, the lighting, the iron, the television, the air conditioner). Typical cycles are defined for the dishwasher and the washing machine, with the duration in minutes and the percentage of the nominal power in every minute of the cycle. At a first glance the other appliances, such as the lighting, do not seem to follow a cycle, but we can regard them as such, considering that, when the user decides to switch them on, then they stay so for an average duration at full power. The formulae for the mean and the variance are as follows:

$$\mu_a = p_a \cdot p_d \cdot p_t \cdot P_{\text{nom}} \cdot \frac{\sum \pi_i}{l+59}$$

$$\sigma_a^2 = p_a \cdot p_d \cdot p_t \cdot P_{\text{nom}}^2 \cdot \frac{\sum \pi_i^2}{l+59} - \mu_a^2$$

where π_i denotes the percentage of the nominal power at minute i of the cycle, l is the duration of the cycle in minutes and $l+59$ is the number of possible power percentages (with 59 of them being zero) at the first minute of hour t , given that the device is used during this hour, starting at a random minute. Again remember parameters are appliance-specific and a is omitted for keeping the notation simple.

Finally, the water boiler has a mixed cycle and on/off behaviour, and its parameters are as follows:

$$\mu_a = p_a \cdot P_{\text{nom}} \cdot \left\{ p_d \cdot p_t \cdot \frac{\sum \pi_i}{l+59} + \frac{l_{\text{on}}}{l_{\text{on}} + l_{\text{off}}} \cdot (1 - p_d \cdot p_t) \right\}$$

$$\sigma_a^2 = p_a \cdot P_{\text{nom}}^2 \cdot \left\{ p_d \cdot p_t \cdot \frac{\sum \pi_i^2}{l+59} + \frac{l_{\text{on}}}{l_{\text{on}} + l_{\text{off}}} \cdot (1 - p_d \cdot p_t) \right\} - \mu_a^2$$

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